ANNUAL REPORT 2001

uniongas

A Duke Energy Company

uniongas
A Duke Energy Company

J.L. (Jane) Peverett
President

May 10, 2002

Dear Shareholder:

I am pleased to forward you a copy of the Union Gas 2001 annual report. You will notice that the format has changed this year from book form to loose-leaf format. This new version of the annual report is cost-effective and at the same time provides a comprehensive review of Union Gas's performance for 2001. It contains Union's financial results, balance sheet and income statement, management's discussion and analysis, statement of corporate governance and corporate directory.

You also can visit our website at www.uniongas.com for electronic versions of Union Gas's 2001 financial statements and management's discussion and analysis.

J. L. Peverett

200 Yorkland Boulevard, Toronto, ON M2J 5C6 tel. 416 496 5300 fax 416 496 5253
Union Gas Limited

AUDITORS' REPORT

To the Shareholders of
Union Gas Limited

We have audited the balance sheets of Union Gas Limited as at December 31, 2001 and 2000 and the statements of income, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2001 and 2000 and the results of its operations and cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Toronto, Ontario
January 25, 2002

Ernst & Young LLP
Chartered Accountants

UNION GAS LIMITED
Statements of Income

For the Years Ended December 31 ($millions)	2001	2000
Gas sales and distribution revenue	1,688	1,401
Cost of gas (note 15)	1,104	796
Gas distribution margin	584	605
Transportation and storage revenue (note 15)	194	180
Other revenue	44	33
	822	818
Expenses		
Operating and maintenance (note 15)	277	271
Depreciation and amortization (note 5)	148	148
Property and capital taxes	55	54
	480	473
Operating income	342	345
Interest expense		
Long-term debt	168	161
Short-term debt (note 15)	13	16
Interest capitalized	(2)	(2)
	179	175
Income before income taxes	163	170
Income taxes (notes 2, 3 and 14)	42	57
Net income	121	113
Preference share dividend requirement	5	5
Earnings applicable to common shares	116	108

(See accompanying notes)

UNION GAS LIMITED
Statements of Retained Earnings

For the Years Ended December 31 ($millions)	2001	2000
Retained earnings, beginning of year	**396**	353
Net income	**121**	113
Dividends		
Preference shares	**5**	5
Common shares	**65**	65
Retained earnings, end of year	**447**	396

(See accompanying notes)

UNION GAS LIMITED
Balance Sheets

As at December 31 ($millions)	**2001**	2000
Assets		
Current assets		
Accounts receivable (notes 3 and 15)	**556**	347
Inventories (note 4)	**239**	174
Income taxes receivable	**73**	-
Deferred income taxes (notes 3 and 15)	**-**	49
	868	570
Property, plant and equipment (note 5)	**3,071**	3,003
Investments and other assets (note 6)	**360**	365
	4,299	3,938
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term borrowings (notes 7 and 15)	**601**	509
Accounts payable and accrued charges (notes 3 and 15)	**210**	256
Income taxes payable	**-**	16
Deferred income taxes (notes 3 and 15)	**57**	-
Long-term debt due within one year (note 8)	**119**	11
	987	792
Long-term debt (note 8)	**1,825**	1,694
Redeemable preference shares (note 9)	**5**	5
Deferred income taxes (note 2)	**289**	301
Shareholders' equity		
Share capital (note 10)	**746**	750
Retained earnings	**447**	396
	1,193	1,146
	4,299	3,938

Contingencies and commitments (notes 11 and 16)
(See accompanying notes)

Approved by the Board

UNION GAS LIMITED

Statements of Cash Flows

For the Years Ended December 31 ($millions)	2001	2000
Operating Activities		
Net income	121	113
Charges not affecting cash		
Depreciation and amortization	150	150
Deferred income taxes	67	(26)
Operating cash flow	338	237
Non-cash working capital changes		
Accounts receivable	(209)	(84)
Inventories	(65)	(84)
Accounts payable and accrued charges and other	(108)	57
	(44)	126
Investing Activities		
Additions to property, plant and equipment	(218)	(204)
Decrease in investments and other assets	5	8
	(213)	(196)
Financing Activities		
Increase in short-term borrowings	92	54
Long-term debt		
Issued	250	185
Retired	(11)	(122)
Preference shares redeemed	(4)	-
Common shares issued	-	23
Dividends	(70)	(70)
	257	70
Change in cash during the year and cash, end of year	-	-

(See accompanying notes)

UNION GAS LIMITED
Notes to Financial Statements
December 31, 2001

1. Significant Accounting Policies

Accounting Principles

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles. The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities.

Regulation

The utility operations are subject to regulation under the Ontario Energy Board Act and the Energy Act (Ontario). Rate schedules are approved periodically by the Ontario Energy Board (OEB) under a performance-based regulatory mechanism and are designed to permit a fair and reasonable return on the utility investment. Realization of the allowed rate of return is subject to actual operating conditions experienced during the year.

The Company operates within southwestern, northern and eastern Ontario under franchise agreements with individual municipalities that are approved by the OEB.

Gas Sales and Cost of Gas

Gas sales revenue is recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the reporting period. Cost of gas is recorded using prices approved by the OEB in the determination of customer sales rates. Differences between the OEB approved reference prices and those costs actually incurred are deferred for future disposition subject to approval by the OEB.

In the matching of gas sales revenue and cost of gas sold, volumetric differences arise from the measurement process. The Company includes in the cost of gas an estimated amount of these volumetric differences based upon the methodology recognized by the OEB in the determination of customer sales rates. Annual fluctuations from the estimated level are deferred and amortized over a period of three years.

Income Taxes

Effective January 1, 2000, The Canadian Institute of Chartered Accountants (CICA) changed the accounting standards relating to the accounting for income taxes to the liability method. The CICA's new standard continues to allow the Company to account for income taxes using the flow through tax accounting methodology as approved by the OEB. Under flow through tax accounting, income tax expense is recorded on the basis of income taxes currently payable. Rates and revenues for utility operations include recovery of only such income taxes as are currently payable. Accordingly, the Company does not provide for income taxes deferred to future years as a result of differences in the treatment for income tax and accounting purposes of various items of income and expenditure. The only exception is that the Company calculates deferred income taxes on temporary differences between the approved cost and the actual cost of gas and other amounts deferred in accounts approved by the OEB.

Prior to 1997, the Company utilized the tax allocation method to account for income taxes. Under this method, provision was made for income taxes deferred principally as a result of claiming capital cost allowance for income tax purposes in excess of depreciation provided in the accounts. Note 2 describes the method for disposition of the accumulated deferred tax balance.

In the event that the Company had implemented the liability method for fiscal 2000, the deferred income tax liabilities and assets and deferred income tax expense would have been:

($millions)	Liability Method		Flow Through Method	
	2001	2000	**2001**	2000
Current deferred income tax asset	-	49	-	49
Current deferred income tax liability	53	-	57	-
Long term deferred income tax liability	397	419	289	301
Deferred income tax expense (recovery)	**52**	(39)	**67**	(26)

Inventories

Gas in storage for resale to customers is carried at prices approved by the OEB in the determination of customer sales rates. Inventories of materials and supplies are valued at the lower of average cost, replacement cost and net realizable value.

Property, Plant and Equipment and Depreciation

Property, plant and equipment are carried at cost which includes all direct costs, overhead attributable to construction and interest capitalized during construction. The cost of property, plant and equipment is reduced by contributions and grants in aid of construction received from customers and governmental bodies in support of specific transmission and distribution facilities.

The original cost of depreciable units retired, together with the net cost of removal less salvage, is charged to accumulated depreciation. Under this method, no income or loss is recognized on ordinary retirements of depreciable property.

Depreciation is provided on the straight-line method at various rates based on the average service life of each class of property, ranging from 4 to 60 years. Depreciation rates are determined by periodic review and approved by the OEB.

Deferred Charges

Costs related to long-term debt are deferred and amortized on a straight-line basis over the term of the respective debt issues.

Goodwill has been recorded at the excess cost of an investment over the fair value of the net assets acquired and is not amortized. Goodwill will be written down to net recoverable value if declines in value, considered to be other than temporary, occur based upon expected undiscounted cash flows.

Employee Benefit Plans

The Company accrues its obligations under employee benefit plans and the related costs, net of plan assets. The plan assets are valued at fair value. The calculation of the expected return on assets is based on the market-related value of assets.

Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment.

The excess of the net unamortized cumulative actuarial gain or loss over 10 per cent of the greater of the benefit obligation and the market-related value of plan assets at the beginning of the year is amortized over the average remaining service period of the active employees.

The average remaining service period of the active employees covered by both the pension plans and the other retirement benefits plans is 17 years.

For defined contribution plans maintained by the Company, contributions payable by the Company are expensed as pension costs.

Natural Gas Swap and Other Contracts

The Company's gas supply portfolio includes contracts with pricing mechanisms that reflect monthly variations in the price of gas, rather than fixed prices. In order to manage price volatility, hedges are used to fix gas prices with respect to the underlying physical gas supply contracts. The hedges include the use of natural gas swaps and purchase price collars. The actual cost of gas purchased includes the impact of any hedging activities related to these contracts. The Company negotiates natural gas swap and purchase price collar contracts only with those institutions that have a credit rating of A or higher.

Comparative Figures

Certain comparative figures have been reclassified to conform to the presentation adopted in 2001.

2. Long-term Deferred Income Taxes

In 1997, following approval by the OEB, the Company changed its accounting for income taxes related to utility operations from the tax allocation method to flow through tax accounting consistent with the determination of 1997 rates. This change was applied prospectively since the basis for determining the Company's rates and revenues for utility operations were previously established taking into account the provision for income taxes based on the tax allocation methodology.

The long-term deferred tax balance of $289 million at December 31, 2001 (2000 - $301 million) includes $282 million (2000 - $293 million) that arose from using the tax allocation methodology related to utility operations. As approved by the OEB, this balance is reduced as the timing differences that gave rise to these deferred income taxes reverse. The timing differences related to utility operations are expected to reverse over approximately 17 years.

3. Income Tax Treatment of Gas Cost and Other OEB Approved Deferral Accounts

The Company has a balance of $204 million receivable (2000 - $14 million payable) that represents income tax temporary differences related to gas costs and other amounts deferred in accounts approved by the OEB.

The Company is required to deduct from or include in taxable income the actual amounts incurred related to these deferral accounts. The change in the deferral account balances during the year resulted in a decrease in taxable income of $218 million (2000 - $22 million increase). The Company recorded a deferred income tax expense of $79 million (2000 - $9 million recovery) with respect to these amounts.

4. Inventories

($millions)	**2001**	2000
Gas in storage	**213**	147
Materials and supplies	**26**	27
	239	174

5. Property, Plant and Equipment

($millions)	**2001**	2000
Cost		
Distribution	**2,577**	2,478
Transmission	**1,053**	999
Storage	**575**	553
General	**270**	256
	4,475	4,286
Accumulated depreciation		
Distribution	**831**	764
Transmission	**324**	299
Storage	**141**	125
General	**108**	95
	1,404	1,283
Net book value	**3,071**	3,003

Gas distribution plant is net of contributions in aid of construction of $158 million (2000 - $153 million). Depreciation rates used during the year ended December 31, 2001 resulted in a composite rate of 3.51% (2000 – 3.56%). In 2001, $2 million (2000 - $2 million) of depreciation was allocated to operating and maintenance expense rather than to depreciation and amortization expense shown on the Statements of Income.

Property, plant and equipment include assets that are not subject to depreciation totalling $118 million (2000 - $111 million). These assets include land, base pressure gas in storage reservoirs and assets under construction.

6. Investments and Other Assets

($millions)	**2001**	2000
UEI Holdings Inc. 5.2% cumulative redeemable preferred shares	**150**	150
Gas for balancing direct purchase customers (a)	**164**	164
Deferred charges and other	**46**	41
Centra Gas Manitoba Inc. 10.625% debentures	**-**	10
	360	365

(a) The Company carries gas for balancing direct purchase customer requirements at cost. Bundled delivery service customers are required to balance their gas supply and gas consumption annually. To provide this service the Company owns gas to meet the customers' demand for gas during the year.

7. Short-term Borrowings

The Company has total bank lines of credit of $765 million. The lines of credit include a committed credit facility of $715 million with a one-year term that commenced in July 2001, and a $50 million operating facility. During the term of the committed credit facility, the Company has the option to convert a portion of the drawings under the facility to loans not exceeding eighteen months. The bank lines of credit are unsecured.

These lines of credit enable the Company to borrow directly from banks, issue bankers' acceptances and support a commercial paper program. A majority of the short-term cash requirements are funded through issuing commercial paper at rates generally below prime. The average interest rate on short-term borrowings for the year ended December 31, 2001 was 4.3% (2000 – 5.7%).

Total short-term interest paid in 2001 was $16 million (2000 - $11 million).

8. Long-term Debt

($millions)	2001	2000
Sinking fund debentures		
11.55% 1988 Series II debentures, due October 15, 2010	**69**	73
13.5% senior debentures due November 14, 2008	**9**	10
10.625% senior debentures due January 7, 2002	**36**	39
10.75% senior debentures due July 31, 2009	**45**	48
Other long-term debt		
10.625% 1989 Series debentures, due July 11, 2011	**125**	125
11.5% 1990 Series debentures, due August 28, 2015	**150**	150
9.7% 1992 Series II debentures, due November 6, 2017	**125**	125
8.75% 1993 Series debentures, due August 3, 2018	**125**	125
7.90% 1994 Series debentures, due February 24, 2014	**150**	150
9.75% 1994 Series II debentures, due December 13, 2004	**125**	125
8.65% 1995 Series debentures, due November 10, 2025	**125**	125
9.7% senior debentures, due December 9, 2002	**75**	75
8.65% senior debentures, due October 19, 2018	**75**	75
8.85% senior debentures, due September 1, 2005	**100**	100
7.8% senior debentures, due December 1, 2006	**75**	75
Medium-term note debentures		
5.7% Series 1, due July 14, 2008	**100**	100
7.2% Series 2, due June 1, 2010	**185**	185
6.65% Series 3, due May 4, 2011	**250**	-
	1,944	1,705
Less: current portion	**119**	11
	1,825	1,694

The Company's long-term debt is unsecured. The weighted average cost of long-term debt for the year ended December 31, 2001 was 8.9% (2000 - 9.2%). Principal repayment requirements on long-term debt are as follows:

		($ millions)
2002	-	119
2003	-	8
2004	-	133
2005	-	108
2006	-	83
Thereafter	-	1,493
Total		1,944

Under the terms of the trust indentures relating to certain debentures, the Company has agreed to limit the payment of dividends and to meet certain interest coverage ratios prior to the issue of additional long-term debt. The Company is in compliance with all such covenants.

Total interest paid on long-term debt in 2001 was $163 million (2000 - $160 million).

9. Redeemable Preference Shares
($ millions)

Authorized	Issued	2001	2000
Preference shares			
Class A – 101,572 shares (2000 – 103,972)	52,072 Series A, 5.5% (2000 – 54,472)	3	3
	49,500 Series C, 5% (2000 – 49,500)	2	2
Class B - unlimited shares	Nil	-	-
		5	5
Less: current portion		-	-
		5	5

The Class A Preference Shares, Series A and C are cumulative and redeemable at $50.50 per share. Through the operation of a purchase fund the Company is obligated to offer to purchase $170,000 of Series A and $140,000 of Series C shares annually at the lowest price obtainable but not exceeding $50 per share.

10. Share Capital
($ millions)

Authorized	Issued	2001	2000
Preference shares			
Class A - 90,000 shares	90,000 Series B, 6%	5	5
Class B - unlimited shares	4,000,000 Series 10, 4.88%	100	100
Class C - unlimited shares	75,000 Series 1 (2000 – 100,000)	14	18
		119	123
Common shares - unlimited shares	57,822,650 shares	627	627
		746	750

The Class A Preference Shares, Series B are cumulative and redeemable at $55 per share.

The Class B Preference Shares, Series 10 are cumulative and redeemable at the Company's option and convertible into Class B Preference Shares, Series 11 every five years commencing January 1, 2004. The dividend rate is fixed until December 31, 2003, at which point the dividend will become floating at an annual rate of 80% of the prime rate.

The Class C Preference Shares, Series 1 are cumulative and mandatorily redeemable on a quarterly basis if in that quarter the Company's corporate tax instalment, which would otherwise have been payable but for the utilization of the Union Energy Inc. (UEI) losses (note 15), is reduced as a result of the use by the Company of the UEI losses. The number of shares redeemed in a quarter is based on the tax instalment reduction realized in the quarter. The proceeds on redemption are payable in either cash or Class C Preference Shares, Series 2. Class C Preference Shares not redeemed by December 31, 2003 will be redeemed without consideration. A quarterly cumulative dividend of 6% per annum of the amount by which the Company's tax instalments have been reduced by the utilization of the UEI losses, will be payable if the Company fails to make quarterly required redemption payments. During 2001, the Company redeemed 25,000 of the Class C Preference Shares, Series 1 for a total of $4 million.

11. Risk Management

Natural Gas Swap Contracts

The purchase price applicable to approximately 86% of the Company's forecast gas supply from January through October 2002 is indexed to either the New York Mercantile Exchange Natural Gas Futures contracts or the Canadian Gas Price Reporter Alberta border average monthly price. At December 31, 2001, the purchase price applicable to 349 10^6m^3 or 12% of this indexed supply has been effectively fixed through the use of natural gas swap contracts and purchase price collars that mature prior to April 2002.

Credit Risk

The Company, in the normal course of its operations, provides from its holdings of gas in storage, gas loans to other parties. The replacement amount of gas loans at December 31, 2001 was $140 million (2000 - $140 million). The Company manages its credit exposure related to gas loans by subjecting these parties to the same credit policies it uses for all customers. The Company maintains credit policies which management believes significantly minimizes overall credit risk.

12. Fair Values of Financial Assets and Liabilities

The following fair value information is provided to comply with financial instrument disclosure requirements. Fair values have been estimated by reference to quoted market prices for the actual or similar instruments where available. The fair value of accounts receivable and current liabilities approximated their carrying amounts in the financial statements due to the relatively short period to maturity of these instruments. The carrying values and fair values (FV) of the Company's other financial instruments are as follows:

($millions)	2001		2000	
	Carrying Value	FV	Carrying Value	FV
Assets				
Centra Gas Manitoba Inc. debentures	-	-	10	10
UEI Holdings Inc. preferred shares	150	150	150	150
Natural gas swap contracts	-	(13)	-	32
Liabilities				
Long-term debt	1,944	2,245	1,705	1,754
Redeemable preference shares	5	5	5	5

Under the regulatory process, the Company recovers the cost of natural gas and the weighted average cost of its long-term debt through its rate setting mechanism. Accordingly, the Company cautions readers that estimated fair values may not be relevant for their purposes.

13. Employee Future Benefits

The Company has defined benefit pension plans, defined contribution pension plans and defined benefit plans providing retirement and post-employment health and life insurance benefits for most employees. The defined contribution pension expense for the year ended December 31, 2001 was $3 million (2000 - $2 million).

Information about the defined benefit plans, in aggregate, for the year ended December 31, 2001 is as follows:

($millions)	Pension Benefit Plans		Other Benefit Plans	
	2001	2000	**2001**	2000
Accrued benefit obligations				
Balance, beginning of year	**354**	349	**42**	40
Current service cost	**7**	7	**1**	1
Interest cost	**24**	24	**3**	3
Benefits paid	**(24)**	(26)	**(1)**	(2)
Prior service costs	**5**	-	-	-
Actuarial gains	**(12)**	-	**19**	-
Balance, end of year	**354**	354	**26**	42
Plan assets				
Fair value, beginning of year		**389**	346	-
-				
Return on plan assets	**(64)**	57	-	-
Employer contributions	**11**	10	**2**	-
Employees' contributions	**2**	2	-	-
Benefits paid	**(24)**	(26)	**(2)**	-
Fair value, end of year	**314**	389	-	-
Funded status – plan surplus (deficit)	**(40)**	35	**(26)**	(42)
Unamortized net actuarial loss (gain)	**43**	(32)	**(19)**	-
Unamortized prior service costs		**5**	-	-
-				
Unamortized transitional obligation	**22**	24	**35**	37
Contributions remitted after measurement date	**2**	-	-	-
Accrued benefit asset (liability)	**32**	27	**(10)**	(5)

The non-pension defined benefit plans are unfunded.

There are also certain defined benefit pension plans that have accrued obligations that exceed their plan assets. For those plans, the accrued benefit obligations are $342 million (2000 - $25 million) and the fair value of plan assets is $300 million (2000 - $12 million).

The following is a summary of the weighted average significant actuarial assumptions used in measuring the Company's accrued benefit obligations:

	Pension Benefit Plans		Other Benefit Plans	
	2001	2000	**2001**	2000
Discount rate	**7.25%**	7.00%	**7.25%**	7.00%
Expected long-term rate of return on plan assets	**8.50%**	7.50%	**N/A**	N/A
Rate of compensation increase		**3.25%**	3.25%	**3.25%**
3.25%				

In addition, in determining the expected cost of health care benefit plans, it is assumed that the inflationary increase of health care costs will decrease gradually from 7% in 2001 to 5% in 2003 and remain level thereafter.

The Company's net benefit plan expense was as follows:

($millions)	Pension Benefit Plans		Other Benefit Plans	
	2001	2000	**2001**	2000
Current service cost	**5**	5	**1**	1
Interest on projected benefit obligation	**24**	24	**3**	3
Return on plan assets	**(29)**	(25)	**-**	-
Amortization of transitional obligation	**2**	2	**2**	2
Net benefit plan expense	**2**	6	**6**	6

14. Income Taxes

The provision for income taxes consists of the following:

($millions)	**2001**	2000
Current	**(25)**	83
Deferred	**67**	(26)
	42	57

A reconciliation between the combined Federal and Ontario statutory tax rate and the effective rate of income taxes is as follows:

	2001	2000
Income before income taxes	**163**	170
Statutory income tax rate (percent)	**40.62**	42.83
Statutory income tax rate applied to accounting income	**66**	73
Increase (decrease) resulting from:		
Dividend income	**(3)**	(3)
Large corporations tax	**9**	8
Deductions claimed for income tax purposes in excess of amounts recorded for accounting purposes	**(7)**	(6)
Deferred income tax rate adjustments	**(8)**	-
Loss for tax purposes carried back to prior year	**(4)**	-
Amortization of deferred income taxes	**(11)**	(15)
Provision for income taxes	**42**	57
Effective rate of income taxes (percent)	**25.8**	33.5

Total income taxes paid in 2001 were $37 million (2000 - $48 million).

15. Related Party Transactions

a. The Company purchases natural gas and transportation services at prevailing market prices and under normal trade terms from commonly controlled companies. During the year ended December 31, 2001, these purchases totalled $53 million (2000 - $45 million). The Company also provides storage and

transportation services to commonly controlled companies under normal trade terms. During the year, this revenue totalled $4 million (2000 - $7 million).

b. The Company provided administrative, management and other services to commonly controlled companies totalling $5 million (2000 - $6 million), which were recovered at cost. Charges from related parties for administrative and other goods and services were $13 million (2000 - $11 million).

c. The Company received dividends from the UEIH cumulative redeemable preferred shares of $8 million (2000 - $8 million).

d. At December 31, 2001, the Company has intercompany receivable balances of $5 million (2000 - $4 million) and intercompany payable balances of $3 million (2000 - $1 million), which are recorded in accounts receivable and accounts payable respectively. At December 31, 2001 the Company had unsecured loans payable of $117 million to its parent company, Westcoast Energy Inc., recorded in short term borrowings. Interest paid on these loans was based on the monthly average of 30-day banker's acceptance rates (2.3% at December 31, 2001) and totalled $4 million in 2001.

e. In December 2000, Union Energy Inc. (UEI) and UEI Holdings Inc. (UEIH), companies related to the Company through common control, completed a corporate reorganization. The corporate reorganization transferred all of the assets and liabilities of UEI to another company controlled by UEIH. The only remaining asset of UEI was a deferred income tax asset associated with losses from prior years, which can be applied to future years' income tax liabilities. Subsequent to the reorganization, the Company purchased all the outstanding shares of UEI from UEIH, in exchange for 100,000 Class C, Series 1 redeemable preference shares of the Company. The transaction has been recorded at $18 million, which is equal to the redemption value of the preference shares and the book value of the deferred income tax asset.

16. Contingencies

The Company, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Accruals are made in instances where it is probable that liabilities will be incurred and where such liabilities can be reasonably estimated. Although it is possible that liabilities may be incurred in instances for which no accruals have been made, the Company has no reason to believe that the ultimate outcome of these matters would have a significant impact on its financial position.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This discussion and analysis of the Company should be read in conjunction with the financial statements and accompanying notes.

AMALGAMATIONS & ACQUISITIONS

Union Gas Limited ("the Company" or "Union") was incorporated under the laws of the Province of Ontario by letters patent dated December 19, 1911. Westcoast Energy Inc. ("Westcoast") owns all of the outstanding common shares of the Company.

In March 2001, Westcoast purchased Empire State Pipeline. The Company has sole responsibility for marketing the capacity of the New York intrastate pipeline. With a capacity of 525 million cubic feet per day, the point-to-point pipeline serves local distribution companies, power generators, marketers and large industries in western New York. The pipeline also gives customers access to eastern markets through interconnects with National Fuel Gas Supply and Dominion CNG. Customers can purchase both firm and interruptible transportation services to the Empire system.

In September 2001, Duke Energy announced plans to expand its position in the North American natural gas marketplace by acquiring Westcoast, Union's parent company, in a cash, stock and debt assumed transaction valued at about (US) $8 billion. Over 96% of the Westcoast security holders voted in favour of the transaction in December. The deal was successfully completed effective March 14, 2002.

Under the new corporate structure, the Company remains a utility regulated by the Ontario Energy Board ("OEB") and is part of Duke Energy Gas Transmission ("DEGT"). As part of DEGT, the Company will continue to adhere to the OEB's affiliate relationship code for gas distributors.

HIGHLIGHTS

Years Ended December 31	**2001**	2000	1999
Earnings applicable to common shares *($millions)*	**116**	108	90
Distribution volumes *(10^6m^3)*	**13 896**	14 933	14 602
Transportation volumes *(10^6m^3)*	**18 613**	20 831	19 972
Customers *(000's)*	**1,147**	1,123	1,104

The Company is a Canadian natural gas utility that provides natural gas distribution, transmission and storage and related services to more than one million residential, commercial and industrial customers in over 400 communities in northern, southwestern and eastern Ontario. Its distribution service area extends throughout northern Ontario from the Manitoba border to the North Bay/Muskoka area, through southern Ontario from Windsor to just west of Toronto, and across eastern Ontario from Port Hope to Cornwall. The Company also provides natural gas storage and transportation services for other utilities and energy market participants in Ontario, Quebec and the United States.

RATE REGULATION

ONTARIO ENERGY BOARD RATES DECISIONS

The Company's rates are subject to regulation by the OEB. Rates have typically been set to recover revenues equal to the forecast costs of the Company, including operating, maintenance and administrative costs, and including debt and equity cost of financing capital investment. Rates were most recently set on this basis for the 1999 calendar year. The OEB's decision for 1999 approved rates was based on an allowed return on common equity of 9.61% on a common equity component of rate base of 35%. The approved rate base was $2,705 million, with an allowed return on rate base (weighted average cost of debt and equity capital) of 9.41%.

In July of 2001 the OEB approved final 2000 rates that, reflected, among other things, an adjustment to increase the allowed rate of return on common equity to 9.95%. The OEB's July 2001 decision also approved a form of Performance Based Regulation ("PBR") for establishing rates, which fixed the allowed rate of return on common equity in rates at the 2000 level of 9.95%.

PERFORMANCE BASED REGULATION

In July 2001, the OEB approved a trial form of PBR for Union. For the years 2001 through 2003, rates will be adjusted by formula from the 2000 rate level by a rate escalator that is increased for annual inflation (the change in the national Gross Domestic Product Price Index) less a fixed factor of 2.5% to provide for productivity gains. There is some pricing flexibility allowed, including the ability to negotiate longer-term rates with customers. Certain items, such as the cost of purchasing gas, will continue to be passed through to customers at cost, the same treatment as existed under cost of service regulation. An earnings sharing mechanism with a band around the approved return on equity ("ROE") of one percentage point after taxes was also established. This mechanism provides equal sharing of any earnings variance outside the band between customers and shareholders. The approved return on equity for purposes of setting the band for earnings sharing, is determined using the OEB formula for ROE and may not reflect the ROE recovered through rates. Under the PBR plan, the Company accepts somewhat more risk than under cost of service regulation in exchange for an increased opportunity to benefit from growth and cost efficiency.

As part of PBR, the Company is required to go through a customer review process. The customer review process is a settlement negotiation that addresses the specific PBR parameters for the applicable period and other matters such as the disposition of deferral accounts. A hearing is then held before the OEB to approve the settlement and hear evidence on unresolved issues. The Company concluded a customer review and hearing before the OEB on April 16 to settle rates for 2001 and 2002. A decision approving final 2001 and 2002 rates is pending. The Company also expects to begin its next customer review process this summer to set rates for 2003.

OPERATING RESULTS

EARNINGS

Years Ended December 31 ($millions)	**2001**	2000	1999
Gas distribution margin	**584**	605	569
Transportation and storage revenue	**194**	180	158
Other revenue	**44**	33	35
Operating expenses	**480**	473	459
Interest expense	**179**	175	168
Income taxes	**42**	57	40
Net income	**121**	113	95
Earnings applicable to common shares	**116**	108	90
Weather normalized earnings applicable to common shares	**138**	113	104

Net income for 2001 was $121 million compared with $113 million in 2000 and $95 million in 1999. After deducting preference share dividends, earnings applicable to common shares were $116 million in 2001, $108 million in 2000 and $90 million in 1999. The increase in earnings in 2001 compared to 2000 was primarily due to the affect of ongoing customer growth, revenue resulting from PBR and lower effective rate of income taxes. These increases were offset in part by warmer weather than 2000 and lower weather normalized use.

The increase in earnings in 2000 compared to 1999 was primarily due to colder weather in 2000 compared to 1999 and ongoing customer growth.

The weather, measured in heating degree-days, was 12.7% warmer than normal in 2001, 2.3% warmer than normal in 2000 and 8.6% warmer than normal in 1999. Normal heating degree-days are determined each year as the simple average of the heating degree-days of the previous 30 years. In 2001, 2000 and 1999, earnings applicable to common shares were reduced by $22 million, $5 million and $14 million respectively, due to warmer weather compared to normal temperatures. This resulted in an increase in earnings in 2001 compared to 2000 of $25 million and an increase in earnings in 2000 compared to 1999 of $9 million.

QUARTERLY RESULTS

	For the quarters ended			
($millions)	Mar	June	Sept	Dec
2001				
Operating revenues	672	367	401	486
Net Income (loss)	83	(5)	(8)	51
2000				
Operating revenues	572	280	210	552
Net Income (loss)	70	7	(18)	54

GAS DISTRIBUTION MARGIN

The gas distribution margin was $584 million in 2001 compared with $605 million in 2000 and $569 million in 1999. The decrease in the margin in 2001 compared to 2000 was largely due to warmer weather in 2001. The increase in the margin in 2000 compared to 1999 was primarily due to colder weather in 2000 and customer growth.

Most of the Company's industrial and commercial customers, and a portion of residential customers, purchase their natural gas supply directly from suppliers or marketers. As the Company earns income from the distribution of natural gas and not the sale of the natural gas commodity, the gas distribution margin is not affected by the source of the customer's gas supply.

Transportation and Storage Revenue

Revenue from the transportation and storage of gas was $194 million in 2001 compared with $180 million in 2000 and $158 million in 1999. The increases over the past two years were due to increases in commodity revenue from higher gas costs, demand for short-term storage and other transactional services. In 2001, this increase was offset by the write-off of gas loans receivable from Enron.

Transportation and storage customers are primarily Canadian natural gas transmission and distribution companies. Approximately 87% of the Company's annual transportation and storage revenue is generated by fixed demand charges under contracts with remaining terms of up to 13.5 years and an average outstanding term of 4.5 years.

Other Revenue

Other revenue was $44 million in 2001 compared with $33 million in 2000 and $35 million in 1999. The increase in of $11 million in 2001 compared to 2000 was primarily due to higher delayed payment charges resulting from the higher cost of gas and revenue from line locate services.

Operating Expenses

Operating and maintenance expense was $277 million in 2001 compared with $271 million in 2000 and $264 million in 1999. The increase in 2001 compared to 2000 was primarily due to higher consulting and contractor services. The increase in 2000 compared to 1999 was partially due to the impact of adopting the new accounting recommendations for employee future benefits. Expenses in 2000 also increased due to higher compressor fuel expense as a result of increased distribution and transportation throughput and the higher cost of natural gas. These increases were offset in part by cost reduction initiatives.

Depreciation and amortization expense was $148 million in 2001 and 2000 compared to $141 million in 1999. The increase in 2000 compared to 1999 was due to a higher investment in property, plant and equipment required to serve the expanding customer base.

Interest Expense

Interest expense was $179 million in 2001 compared to $175 million in 2000 and $168 million in 1999. The increase each year was due to higher average long-term debt outstanding, offset in part by a lower weighted average cost of long term debt. As well, average short-term borrowings and short-term interest rates were higher in 2000 compared to 1999.

Income Taxes

The Company accounts for income taxes using the flow through tax accounting methodology as approved by the OEB. Under flow through tax accounting, income tax expense is recorded on the basis of income taxes currently payable. Rates and revenues for utility operations include recovery of only such income taxes as are currently payable. Accordingly, the Company does not provide for income taxes deferred to future years as a result of differences in the treatment for income tax and accounting purposes of various items of income and expenditure. The only exception is that the Company calculates deferred income taxes on temporary differences between the approved cost and the actual cost of gas and other amounts deferred in accounts approved by the OEB.

Prior to 1997, the Company utilized the tax allocation method to account for income taxes. Under this method, provision was made for income taxes deferred principally as a result of claiming capital cost allowance for income tax purposes in excess of depreciation provided in the accounts. As approved by the OEB, this balance is reduced as the timing differences that gave rise to these deferred income taxes reverse. The timing differences are expected to reverse over approximately 17 years.

The effective rate of income taxes was 25.8% in 2001, 33.5% in 2000 and 29.6% in 1999. The decrease in the effective tax rate in 2001 compared to 2000 was primarily due to deferred income tax rate adjustments and a reduction in federal and provincial income tax rates. The increase in the effective rate in 2000 compared to 1999 was primarily due to a decrease in deductions claimed for income tax purposes in excess of amounts recorded for accounting purposes. This was partially offset by an increase in the amortization of deferred income taxes.

For 2002 and beyond, the Company expects that further reductions to both the provincial and federal tax rates to continue as proposed by the respective governments. Although these reductions will reduce the Company's effective tax rate, the Company is proposing that there is no change to customer service rates since these reductions are inherently reflected in the current performance based regulatory plan used for setting rates.

FINANCIAL CONDITION

Operations

Cash flow from operating activities after non-cash working capital changes was an outflow of $44 million in 2001 compared with an inflow of $126 million in 2000 and $155 million in 1999. The decrease in operating funds in 2001 compared to 2000 was primarily due to increased receivables for gas deferral balances and income taxes. The decrease in operating funds in 2000 compared to 1999 was primarily related to higher levels of accounts receivable and inventories resulting from the increased cost of natural gas. This was partially offset by higher net income in 2000.

Investment Activities

Capital expenditures totalled $218 million in 2001 compared to $204 million in 2000 and $222 million in 1999. Of the total 2001 investment, 37% was spent on transmission and storage projects, 48% on distribution projects and 15% on projects of a general nature. These investments were necessary to meet the growth in customer demand for services. Capital expenditures are expected to be approximately $237 million in 2002.

Liquidity and Capital Resources

The Company meets its cash requirements through funds generated from operations, issuance of short-term debt, long-term debt and preference shares, and common equity investment by the Company's parent.

The Company has total bank lines of credit of $765 million. The lines of credit include a committed credit facility of $715 million with a one-year term that commenced in August 2001, and a $50 million operating facility. During the term of the committed credit facility, the Company has the option to convert drawings under the facility to loans not exceeding eighteen months. These lines of credit enable the Company to borrow directly from banks, issue bankers' acceptances and support a commercial paper program. Most of the short-term cash requirements are funded through issuing commercial paper at rates generally below prime.

The short-term borrowing levels fluctuate significantly during the year due to the funding of construction activities, the timing of long-term debt issues and other financing activities, and the seasonality of the Company's business. The peak borrowings during 2001 reached approximately $601 million in December.

The Company has a medium-term note (MTN) program that allows for the ongoing offering of unsecured MTN debentures under a shelf prospectus. The current shelf prospectus was filed in June 2000 and permits the issuance of medium-term notes in one or more series up to an aggregate principal amount of $400 million over its two-year life. The Company issued $250 million of the MTN debentures in May 2001. The proceeds from this issue were used to repay short-term indebtedness incurred to finance capital expenditures and for other corporate purposes.

Under its previous shelf prospectus, which matured in June 2000, the Company had issued $185 million of MTN debentures in May 2000 and $100 million in July 1998. The proceeds from these issues were also used to repay short-term indebtedness incurred to finance capital expenditures and for other corporate purposes. The Company did not issue any long-term debt in 1999.

Long-term debt repayments on sinking fund debentures totalled $11 million in 2001. Long-term debt repayments in 2000 totalled $122 million. This amount included the early redemptions of the 13.375% 1980 Series debentures in the amount of $35 million and the 10.625% 1986 Series debentures in the amount of $75 million. Long-term debt repayments on sinking fund debentures totalled $12 million in 1999.

Common equity is provided periodically by the Company's parent in order to maintain the common equity component of rate base as approved by the OEB. Common shares were issued by the Company in 2000 in the amount of $23 million.

In 2001, the Company redeemed preference shares totalling $4 million related to the Class C, Series 1 preference shares.

The Company's capital instruments are rated as follows:

		Standard & Poor's	Dominion Bond Rating Service
Commercial paper	A – 1 (mid)	R - 1 (Low)	
Debentures	A +	A	
Preference shares	P-1 (low)	Pfd - 2	

GAS SUPPLY

The gas supply portfolio includes both fixed price contracts and contracts with pricing mechanisms that reflect monthly variations in the price of gas. These contracts are indexed to either the New York Mercantile Exchange (NYMEX) natural gas futures contracts or the Canadian Gas Price Reporter Alberta border average monthly price. Approximately 86% of the Company's forecast gas supply from January through October 2002 is subject to indexed prices.

The Company has a risk management policy that is designed to reduce the price volatility of its gas supply. Hedges are used to fix gas prices with respect to the underlying physical gas supply contracts and include the use of natural gas swaps and purchase price collars. During the year ended December 31, 2001, the Company hedged the purchase price applicable to 24% of its indexed gas supply. At December 31, 2001, the Company had entered into natural gas swap contracts to effectively fix the purchase price for approximately 348 10^6m^3 or 12% of the indexed gas supply from January through October 2002.

In 2002, firm gas supply contracts represent approximately 36% of the Company's total forecast gas supply. Most of these contracts are subject to price re-determination as of November 1, 2002. The remaining 64% of gas purchases include spot gas and other non-contracted supplies.

Gas costs are included in customer rates based on forecasts approved by the OEB. Differences between the OEB approved reference prices and the actual cost of gas purchased, including the impact of both the indexed purchase prices and any hedging activities, are deferred for disposition as approved by the OEB.

ENVIRONMENT, HEALTH AND SAFETY MANAGEMENT PROGRAM

The Company is guided by the principles of sustainable development and strives to ensure that environmental, social and economic issues are considered during the processes of planning, construction and operations to ensure that the environmental and human needs are supported both in the present and for future generations.

Environmental protection, health, and safety are considered to be both corporate and personal responsibilities for the Company and its employees. During 2001, the Company continued its implementation of an environment, health and safety management system to ensure continued compliance with applicable regulations and to provide a consistent approach to policies, programs and procedures. Additional emphasis was placed on training employees on workplace hazards. The management system forms the foundation that allows the continuous improvement of the Company's environment, health and safety performance.

The Company believes that natural gas is part of the solution to climate change. As the least carbon intensive fossil fuel, natural gas will play an important role in meeting today's growing energy needs, while bridging the transition to tomorrow's new, renewable energy sources. The Company continually encourages and engages customers to convert to natural gas and use it more efficiently.

These activities are integral to the Company's daily activities. The Company believes that these programs make sound business sense.

OUTLOOK

Market

Supported by plentiful existing and potential supply, growing demand and additional transportation infrastructure, the North American natural gas industry continues to have a positive long-term future as natural gas remains an environmentally acceptable, cost effective energy choice for consumers and industry.

In the short term, natural gas demand has been affected by the price spike in late 2000 and early 2001. These spikes that peaked at over $15 Cdn/GJ affected a wide range of industrial demands. In addition, the economic slowdown that occurred during the later half of 2001 also affected demands. Since the later half of 2001, prices have fallen to $3.50 Cdn/GJ. At this price level and with oil at over $20 US/barrel, natural gas is competitively priced. Union continues to promote the value of natural gas to both residential and industrial customers.

The lower gas costs result in decreased operating costs for the Company and decreased requirements for working capital to finance gas inventories and customer accounts receivables. High negative balances in the 2001 gas cost deferral accounts are expected to be recovered from customers in 2002.

The ratio of market activity to gas in storage is growing at a remarkable rate at the Company's Dawn storage hub. During 2001, the hub handled an average of 11.9 Bcf/day of title transfers – more than 55% higher than the previous year's total. Through a variety of online trading services and with easy access to downstream markets, Dawn offers customers a vast array of market choices and options. Dawn storage is one of the fastest growing hubs in North America.

The regulatory and competitive environment in Ontario is evolving and the Company is adapting its business practices to meet these changes and maintain its competitive position in its markets. The Company is taking action to manage the risks and benefits from the opportunities presented in a more competitive environment, including the development of new service capability, and the implementation of a performance based method of regulation.

In early 2000, the OEB established a Task Force to recommend rules regarding conditions of access to distribution services by customers and certain standards of business practice as they relate to gas marketers. Topics considered included customer connection and delivery obligations, consumer mobility, billing support services to marketers, prudential (credit) requirements, access to and use of customer information and compliance requirements. The Task Force completed its work and forwarded a report in June 2000. The OEB Staff issued a draft rule for comment on February 6, 2001 and has received comments from interested parties. An oral consultation was held in June 2001. The Board is now considering the comments before issuing a final rule.

The outlook for the Company continues to be positive, supported by growing demand for natural gas, plentiful existing and potential supply, additional transportation infrastructure and strong environmental support for natural gas as an appropriate alternative to other fossil fuels and nuclear energy. The Company's large and diverse customer base, extensive distribution system, and the strategic location of its storage and transmission facilities, with interconnections between major U.S. markets in Michigan and New York state, will provide a sound basis for future growth.

Risk Factors

The Company's earnings are affected by business risks inherent in the natural gas industry and energy marketplace. In general, the earnings level is affected by general economic conditions, the Company's ability to generate forecast revenues, warmer weather, declining use per customer, cost escalation, employee retention and the OEB's decisions with respect to rates.

Market Risk - The average amount of natural gas consumed by residential customers continues to decline slightly. This decline is caused primarily by the replacement of older heating equipment by newer, more efficient equipment and by more energy-efficient housing. Consumption can also be affected by volatile commodity prices as customers become more concerned with the potential for large retroactive charges.

Sales to industrial customers are affected by economic conditions and the price of competitive energy sources. In 2002, approximately 11% of the contract industrial volume is at risk due to the ability of these customers to switch to an alternative fuel.

The transportation and storage business is affected by competition for energy services in the North American energy marketplace, as well as economic conditions. Approximately 25% of the revenues are variable in this market segment.

Commodity Risk - Fluctuations in natural gas prices affect the Company's gas purchase costs for its own operating requirements as well as the gas supply costs it incurs for, and collects from, its system customers. The Company manages this exposure through a risk management committee and policies and employs both fixed and variable price contracts. Hedges are used to fix gas prices with respect to the underlying indexed gas supply contracts and include the use of natural gas swaps and purchase price collars.

Credit Risk - The Company, in the normal course of its operations, provides from its holdings of gas in storage, gas loans to other parties. The replacement amount of gas loans at December 31, 2001 was $140 million. The Company manages its credit exposure related to gas loans by subjecting these parties to the same credit policies it uses for all customers. The Company maintains credit policies that management believes significantly minimize overall credit risk.

Weather Risk - The rates allowed by the OEB are based on forecasts assuming normal weather conditions. Since a large portion of the gas distributed to the higher margin residential and commercial market is used for space heating, differences from normal weather have a significant affect on the consumption of gas.

Weather normalization is a method used to estimate the average or typical annual weather effect on natural gas consumption for a future year. Prior to 2002, the Company used a 30-year rolling average of annual heating degree-days to forecast the weather effect on expected demand. This method for normalizing weather consistently overestimates the heating demand by customers by about 6.8% in a typical year. Beginning 2002, for internal purposes, the Company has moved to a 20-year trend for forecasting weather as this method more fairly reflects the observed warming trend on weather in recent years. The weather normalization assumptions used in setting rates approved by the Ontario Energy Board still reflect the 30-year rolling average methodology.

Regulatory Risk - The changes to the regulatory environment are increasing the risk of the business as more responsibility is placed on the Company to optimize its revenues and costs. With the opening of the competitive electricity market in Ontario scheduled for May 1, 2002, it is expected that electricity may become a more competitive energy alternative. The Company has also accepted more risk from a longer

term PBR plan and floating inflation factor in its price cap formula than it previously incurred under an annual cost of service regime. The Company plans to manage these risks through profitable growth and cost efficiency opportunities.

Human Resources Risk - The Company's workforce consists of both unionized and non-unionized employees. Labour disruptions associated with the collective bargaining process can affect upon the Company's ongoing operations. In addition, the Company must maintain its ability to attract and retain employees with the requisite skills and capabilities to operate in the complex and competitive energy industry.

Other Risks - The Company has approximately 400 franchise agreements with municipalities in Ontario. These agreements set out the terms and conditions under which the Company conducts its business on municipal roadways. Currently the Company is responding to litigation to renew its franchise agreement with the Township of Pittsburgh, a suburb of Kingston. The Company expects that it will receive a favourable court decision on this matter.

STATEMENT OF CORPORATE GOVERNANCE PRACTICES

General

The Board believes that a sound and effective corporate governance system is essential to the well being of the Corporation and its shareholders. The Board has carefully considered the corporate governance guidelines adopted by The Toronto Stock Exchange ("TSE guidelines") and has put in place suitable and effective processes and structures to guide the direction and management of the business and affairs of the Corporation.

Board of Directors

The Board oversees the conduct of the business of the Corporation and the activities of management. Management is responsible for the day-to-day operations of the business. The Board acts independently of management either directly or through the Audit Committee of the Board which is delegated some of the Board's responsibilities. The Board's fundamental objectives are to enhance and preserve long-term shareholder value and to ensure the Corporation meets its obligations on an ongoing basis and operates in a reliable and safe manner.

- **Composition of the Board**

The Board is comprised of 5 directors which it believes is adequate to effectively discharge its responsibilities. All of the voting shares of the Corporation are held by Westcoast Energy Inc. ("Westcoast"). Westcoast is therefore the significant shareholder of the Corporation.

Based on an assessment of each individual director's relationship with the Corporation and with others having relationships with the Corporation, the Board has concluded that all of the directors of the Corporation are unrelated. In conducting its analysis, the Board applied the definition of an unrelated director as one who is independent of management and is free from any interest and any business or other relationship which could, or could reasonably be perceived to, materially interfere with the director's ability to act with a view to the best interests of the Corporation, other than interests and relationships arising from shareholdings. Mr. Brown is an unrelated director. Mr. Evans is a full-time officer of Duke Energy Gas Transmission Corp., an affiliate of the Corporation and an affiliate of Westcoast, the Corporation's significant shareholder. Mr. Evans is not a related director of the Corporation under the TSE guidelines. Two of the directors, Mr. Reid and Mr. Unruh, are full-time officers of Westcoast and are not related directors under the TSE guidelines. Arthur H. Willms, who retired as President and Chief Operating Officer of Westcoast on October 31, 1999 after holding various positions within the Corporation since 1971, provided services to the Corporation until April 30, 2002 and is a director of Westcoast and certain other of its affiliates. He is viewed as unrelated.

The Corporation is of the view that the composition of the Board fairly reflects the investment in the Corporation by shareholders other than Westcoast, the holder of 100% of the issued and outstanding voting shares of the Corporation.

- **Responsibilities of the Board**

The Board has retained responsibility for the Corporation's governance system and is responsible for establishing criteria for Board membership, composition of the Board and the Audit Committee, assessing directors' and Board performance on an ongoing basis and ensuring that there is in place an orientation and education program for new members of the Board.

The Board also has responsibility for the search for and recommendation of new candidates for election to the Board. In identifying such candidates for election, the Board seeks to select well-qualified candidates with a diversity of background, experience and expertise to maintain a well-balanced and highly competent group of directors with the ability to act together effectively. Special attention is given to candidates who have broad business exposure and are financially literate.

The Board is responsible for reviewing human resources and compensation policies and guidelines for application to the Corporation. It is also responsible for ensuring that the Corporation has a process to provide for the development and orderly succession of the Corporation's senior management personnel.

The Board is responsible for reviewing and monitoring the environmental policies and activities of the Corporation and the activities of the Corporation as they relate to the health and safety of the Corporation's employees in the workplace.

Audit Committee

The Board has an Audit Committee that meets regularly and operates under specific terms of reference approved by the Board. These terms of reference are reviewed periodically and modified where appropriate. The Audit Committee is composed entirely of unrelated directors. A calendar of activities for the Audit Committee is prepared annually and approved by the Board.

The Audit Committee is broadly responsible for ensuring that the Corporation's management has designed and implemented an effective system of internal financial controls and financial reporting. It is also responsible for ensuring compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters and the disclosure of material facts. As part of its function, the Audit Committee monitors the appropriateness and effectiveness of the Corporation's policies and business practices which impact on the financial integrity of the Corporation, including those relating to internal auditing, insurance, accounting, information services and systems and financial controls, management reporting and risk management. The Audit Committee reviews, at least annually, the independence of the Corporation's external auditors to satisfy itself of their independence as auditors.

Shareholder Feedback and Concerns

The Corporation has adopted a disclosure policy which establishes procedures to provide the public with broad disclosure on a timely basis of material information concerning the

affairs of the Corporation. The Corporation's practices encourage the free flow of accurate and appropriate communication and, at the same time, discourage selective disclosure of material information that has not been publicly disclosed.

Decisions Requiring Board Approval

The Board discharges its responsibilities directly and through the Audit Committee. In addition to those matters which in law must be approved by the Board, the Board retains the responsibility for the approval of matters of a material nature including the approval of major transactions, the adoption and implementation of the strategic plan, the approval of the annual operating and capital budgets, capital expenditures and financial commitments above approved minimum thresholds, the approval of the Corporation's dividend policy and the monitoring of the principal risks of the business and activities of the Corporation. It also manages its own affairs including the development of the Board's meeting agendas, the nomination of candidates for election to the Board, membership to committees of the Board and director's compensation.

Expectations of Management

Ongoing, the Board expects management to be accountable for the Corporation's financial and competitive performance at a high standard consistent with enhancing the Corporation's value. It also expects management to provide to the Board timely, complete and accurate information on the business operations of the Corporation and to provide for the development of its executives and a plan for their succession.

DIRECTORS

William C. Brown[1]
Corporate Director

Robert B. Evans
Chairman of the Board

Robert T. Reid[1]
Corporate Director

David G. Unruh
Corporate Director

Arthur H. Willms[1]
Corporate Director

[1] Member of the Audit Committee

OFFICERS

Dorothy Ables
Senior Vice President, Financial and Administration

Stephen W. Baker
Vice-President, Gas Supply

M. Richard Birmingham
Vice-President, Regulatory Affairs and Business Services

Bohdan Bodnar
Vice President, Human Resources

Joachim W. Castelsky
Assistant Treasurer

Stephen DeMay
Vice President

Pat Elliott
Controller

Robert B. Evans
Chairman of the Board

Lawrence W. Fedchun
Assistant Secretary

Lindsay A. Hall
Vice President, Finance and Treasurer

Alan Harris
Senior Vice President, Strategic Development and Planning

Leigh A. Hodgins
Assistant Secretary

Theopolis Holeman
Senior Vice President, Transmission and Engineering

Christine L. Jackson
Assistant Secretary

Sherwood L. Love
Assistant Treasurer

Jane L. Peverett
President

Bruce Pydee
Vice President and General Counsel

Kelly Stark-Anderson
Corporate Secretary

John W. Wellard
Vice-President, Sales and Marketing

Mel Ydreos
Vice-President, Operations

CORPORATE INFORMATION

Transfer Agent and Registra
CIBC Mellon

Union Gas Limited preferen
shares are listed on the Toro
Stock Exchange
Class A - 5½% (UNG.PR.C)
Class A – 6% (UNG.PR.D)

REGISTERED OFFICE
50 Keil Drive North
Chatham, Ontario
N7M 5M1

Union Gas Limited
50 Keil Drive North
Chatham, Ontario
N7M 5M1
www.uniongas.com